# SUPPLEMENTAL INFORMATION FOR BOILER 12 MINOR PERMIT REVISION APPLICATION

Buffalo Trace Distillery, Inc. (BTD) operates a facility in Frankfort, Kentucky. The Frankfort distillery is subject to the air quality requirements established by Title V Operating Permit V-12-056 issued by the Kentucky Division for Air Quality (KDAQ) on August 14, 2013.[1]

On February 12, 2018, BTD submitted the 'Application to Renew and Revise a Title V Air Permit' prepared by The EC Group to KDAQ. In addition to satisfying Title V renewal requirements, BTD also used this application to request a significant permit revision involving the addition of a new 179.2 MMBtu/hr natural gas-fired boiler (Boiler 12, Emission Unit 16). The application contained a regulatory review, emissions calculations, and requisite forms (DEP7007AI, DEP7007A, DEP7007N, and DEP7007V) for the proposed boiler. According to an April 6, 2018 letter from Benita Stephens (KDAQ) to Harlen Wheatley (BTD), a preliminary review of the renewal application was concluded on April 3, 2018 and indicated that the application was complete. This renewal application was assigned Activity Number APE20180001 by KDAQ.

Although the combined Title V renewal/Boiler 12 application had already been deemed complete by KDAQ, Michael Kennedy (KDAQ) requested that the Boiler 12 installation be processed as a minor permit revision under 401 KAR 52:020 Section 14. KDAQ then opened a new Activity Number (APE20180003) for the new boiler installation.

After receiving the determination of completeness from KDAQ, BTD constructed Boiler 12 at the end of 2018 and began operating the unit on January 15, 2019; however, KDAQ has not yet issued the Boiler 12 permit.[2] During a meeting with KDAQ on June 5, 2019, Zachary Bittner (KDAQ) requested that BTD supplement the minor permit application materials previously submitted to ensure their accuracy and completeness. This supplement is intended to satisfy KDAQ's request and clarify applicable requirements for Boiler 12.

A description of the Boiler 12 project and regulatory review are provided below, as well as an analysis of potential emissions from the unit. This letter, associated DEP7007 forms (see **Attachment A**), supporting emission calculations (see **Attachment B**), and suggested permit language (see **Attachment C**) satisfy the application requirements for the minor permit revision.

## AIR EMISSIONS QUANTIFICATION

The DEP7007N forms provided in **Attachment A** document the potential to emit (PTE) for Boiler 12 and identify corresponding emission factors based on the proper source classification code (SCC). Furthermore, **Attachment B** provides a complete summary of the parameters used in the potential emissions calculations for Boiler 12. In general, potential emissions calculations rely on the rated maximum heat input capacity of the boiler (179.2 MMBtu/hr [HHV]), continuous annual operation

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[1] Although the Title V permit expired on August 14, 2018, it remains in effect until an operating permit renewal is issued. BTD submitted a renewal application on February 12, 2018.

[2] KDAQ put a hold on work related to BTD's Title V renewal and Boiler 12 permit until certain issues could be resolved.

(8,760 hours per year), and EPA's AP-42 emission factors from Chapter 1.4 for natural gas combustion with the following exceptions:

- The $NO_X$ emission factor (30 ppmvd @ 3% O2) represents a vendor estimate. This estimate reflects the implementation of Low $NO_X$ Burners (LNBs) and a Flue Gas Recirculation (FGR) system to control $NO_X$ emissions from Boiler 12. This vendor-supplied exhaust concentration is used, along with a conservative estimate of the boiler's maximum exhaust flow rate, to determine potential $NO_X$ emissions from continuous annual operations.
- Potential greenhouse gas (GHG) emissions from the boilers are calculated using the appropriate factors from Subpart C of EPA's Mandatory GHG Reporting Rule codified in 40 CFR 98, along with the Global Warming Potentials (GWP) established by Subpart A

**Attachment B** presents detailed emission calculations for the unit.

## REGULATORY REVIEW

The following subsections discuss the applicability of regulatory requirements for the installation of Boiler 12 at BTD.

### *Prevention of Significant Deterioration*

Federal construction permitting programs regulate new and modified sources of attainment pollutants under the Prevention of Significant Deterioration (PSD) program and new and modified sources of non-attainment pollutants under Non-Attainment New Source Review (NA-NSR). BTD is located in Franklin County, Kentucky, which is designated as in attainment/unclassifiable for all pollutants. Therefore, PSD permitting is potentially applicable to the facility. The PSD preconstruction permitting program in Kentucky has been approved by the US EPA and incorporated into the Kentucky State Implementation Plan (SIP) under 401 KAR 51:017 to implement the federal requirements of 40 CFR 51.166 or 52.21.

For the purposes of the PSD permitting program, a *major stationary source* can be summarized as:

- One of the 28 listed stationary sources that emits, <u>or</u> has the potential to emit, 100 tons per year (tpy) or more of any regulated NSR pollutant, where fugitive emissions from the listed source category must be <u>included</u> in the total; <u>or</u>
- Any source not belonging to one of the listed source categories that emits, <u>or</u> has the potential to emit, 250 tpy or more of any regulated NSR pollutant, where fugitive emissions are <u>not included</u> in the total.

As part of the Title V Renewal Activity Number APE20180001, BTD requested emissions limits for the entire facility of less than 250 tpy for 1) VOC and 2) $PM/PM_{10}/PM_{2.5}$ for all non-fugitive sources, as well as synthetic emissions limits covering all "fossil fuel boilers (or combinations thereof) totaling more than 250 MMBtu/hr heat input" of less than 100 tpy for NOx and CO. These limits were requested to preclude the applicability of the PSD permitting requirements under 401 KAR 51:017 and to establish the distillery as a minor source under the PSD program.

As an existing minor source, PSD permitting is triggered for a regulated NSR pollutant only if the project itself is considered a major stationary source. As demonstrated by Table 1, maximum potential emissions from Boiler 12 are less than 100 tpy of each pollutant with the exception of GHGs[3]. Therefore, PSD permitting is not required for the Boiler 12 project. Even if Boiler 12's PTE was compared to the Significant Emission Rates (SERs) that would apply if BTD was classified as an existing major PSD source, Table 1 demonstrates that PSD permitting would not be triggered for the Boiler 12 installation project.

**Table 1. Boiler 12 PTE Compared to PSD MSTs and SERs**

| Pollutant[4] | Boiler 12 PTE (tpy) | PSD MST (tpy) | PSD SER (tpy) |
|---|---|---|---|
| CO | 64.6 | 100 | 100 |
| $NO_X$ | 28.6 | 100 | 40 |
| PM | 5.85 | 100 | 25 |
| $PM_{10}$ | 5.85 | 100 | 15 |
| $PM_{2.5}$ | 5.85 | 100 | 10 |
| $SO_2$ | 0.46 | 100 | 40 |
| VOC | 4.23 | 100 | 40 |
| Pb | 0.0004 | 100 | 0.6 |
| $CO_2e$ | 91,910 | 75,000[5] | 75,000[6] |

### *NSPS Db – Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units*

Based on its heat input capacity (i.e. greater than 100 MMBtu/hr) and installation date (i.e. after June 19, 1984), Boiler 12 is subject to a federal emissions standard under New Source Performance Standard Subpart Db (NSPS Db), which is codified in 40 CFR 60. Specifically, the new boiler is subject to a $NO_X$ standard and associated compliance demonstration requirements, but exempt from the $SO_2$ and PM standards, as described below.

Per 40 CFR 60.42b(k)(2), units firing only very low sulfur oil, gaseous fuel, a mixture of these fuels, or a mixture of these fuels with any other fuels with a potential $SO_2$ emission rate of 0.32 lb/MMBtu or less are exempt from the $SO_2$ emission limits in 40 CFR 60.42b(k)(1). Boiler 12 will fire only natural gas and will have a potential $SO_2$ emission rate less than 0.32 lb/MMBtu[7]; therefore, the $SO_2$ emission limits in this section do not apply. Furthermore, the PM standards of NSPS Db only apply to coal, oil, wood, and municipal solid waste (MSW)-fired boilers and are therefore not applicable to Boiler 12.

Based on the design heat release rate for Boiler 12 (i.e., greater than 70,000 Btu/hr-ft$^3$), the boiler represents a high heat release rate unit and is subject to a $NO_X$ limit of 0.20 lb/MMBtu under 40 CFR

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[3] A facility only triggers PSD requirements for GHG emissions if the requirements are also triggered for a traditional NSR pollutant.

[4] SERs exist for additional pollutants (e.g. Fluorides) not listed in Table 4-1; however, pollutants not listed are not emitted in substantially high enough quantities from BTD to warrant further evaluation.

[5] The 75,000 tpy threshold for carbon dioxide equivalents ($CO_2e$) is treated as a PSD MST only if the facility is a new major stationary source for a regulated NSR pollutant other than GHGs.

[6] The 75,000 tpy threshold for $CO_2e$ is treated as a PSD SER only for projects that would otherwise trigger PSD for at least one traditional non-GHG pollutant.

[7] The AP-42 emission factor for $SO_2$ emissions from natural gas combustion (Section 1.4) corresponds to 0.0006 lb/MMBtu.

60.44b(a). The vendor's guarantee for Boiler 12 (i.e., 30 ppmv @ 3% O2, which corresponds to 0.04 lb/MMBtu) ensures that the unit achieves compliance with the NSPS Db limit. BTD will demonstrate compliance with this limit on a 30-day rolling average basis (including periods of startup, shutdown, or malfunction) using a Continuous Emissions Monitoring Systems (CEMS) for measuring $NO_X$ and a diluent gas (either $O_2$ or $CO_2$). The CEMS comply with applicable Performance Specifications established by Appendix B to 40 CFR 60. Furthermore, BTD is implementing a Quality Assurance Plan (QAP) to ensure compliance with the regulatory requirements established by Appendix F to 40 CFR 60 and the data completeness requirements of NSPS Db.

BTD completed the initial Relative Accuracy Test Audit (RATA) on May 16, 2019 and certified the CEMS within 180 days of startup.[8] For the initial compliance demonstration, BTD is in the process of monitoring $NO_X$ for 30 successive steam generating unit operating days. The 30-day average emission rate (i.e., the average of all hourly emissions data recorded by the monitoring system during the 30-day test period) will be used to determine compliance with the $NO_X$ limit. Following this initial demonstration, BTD will show compliance with the $NO_x$ standard on a continuous basis through the use of a 30-day rolling average emission rate. A new 30-day rolling average emission rate will be calculated each steam generating unit operating day as the average of all of the hourly $NO_x$ emission data for the preceding 30 steam generating unit operating days.

The applicable requirements of NSPS Db are detailed in the DEP7007V forms in **Attachment A** and summarized by the suggested draft permit language in **Attachment C**. BTD will ensure compliance with the applicable notification, reporting, and recordkeeping requirements of NSPS Db.

### *NESHAP JJJJJJ – NESHAP for Industrial, Commercial, and Institutional Boilers at Area Sources*

National Emission Standard for Hazardous Air Pollutants Subpart JJJJJJ (NESHAP JJJJJJ), codified in 40 CFR 63, establishes emission limitations and work practice standards for HAP emissions from industrial, commercial and institutional boilers and process heaters located at area sources of HAP; however, according to 40 CFR 63.11195(e), this regulation does not apply to "gas-fired units".[9]

BTD is an area source of HAP and Boiler 12 will only fire natural gas. Accordingly, Boiler 12 meets the regulatory definition of gas-fired unit and is exempt from NESHAP JJJJJJ requirements.

### *401 KAR 59:015 - New Indirect Heat Exchangers*

Boiler 12 is subject to various requirements under Title 401, Chapter 59:015 of the Kentucky Administrative Regulations (401 KAR 59:015). Specifically, this regulation establishes a PM emission limit, $SO_2$ emission limit, opacity limit, and startup/shutdown requirements for the new boiler. As the distillery's aggregate heat input capacity before and after the Boiler 12 project exceeds 250 MMBtu/hr, the requirements from this regulation that apply to the new boiler are identical to the applicable requirements for the existing boilers. Specifically, the following limits apply to Boiler 12:

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[8] Boiler 12 has yet to achieve full capacity operation as defined by NSPS Db (i.e., "operation of the steam generating unit at 90 percent or more of the maximum steady-state design heat input capacity"). Accordingly, the requirement to complete the initial certification within 60 days of achieving maximum production was not triggered and the initial certification for Boiler 12 was completed within 180 days of startup as required.

[9] Gas-fired units may only burn liquid fuel during periods of gas curtailment, gas supply emergencies, or periodic testing on liquid fuel. Periodic testing of liquid fuel shall not exceed a combined 48 hours during any calendar year.

- PM emissions shall not exceed 0.1 lb/MMBtu on a three-hour average basis.
- Visible emissions shall not exceed twenty (20) percent opacity, with exceptions for cleaning the fire box, blowing soot, and building a new fire (which do not apply to Boiler 12 as a gas-fired unit).
- $SO_2$ emissions shall not exceed 0.8 lb/MMBtu based on a twenty four-hour average.

The applicable requirements of 401 KAR 59:015 are detailed in the DEP7007V forms in **Attachment A** and summarized by the suggested draft permit language in **Attachment C**.

## PERMITTING REQUIREMENTS

### *Requested Changes to Title V Permit*

401 KAR 52:020, Section 14(3)(d), specifies that a modified version of the existing Title V permit with new text to reflect the proposed modification should be included with a minor revision application. This requirement is satisfied through the inclusion of the suggested permit in **Attachment C**.

### *Qualification for Treatment as a Minor Revision*

This permit application seeks to revise the current Title V permit to reflect the installation of Boiler 12 as described in this application letter and its attachments. 401 KAR 52:020, Section 14 provides procedures for existing Title V sources to obtain minor permit revisions for modifications that meet certain criteria. An analysis of these criteria for this permit action is provided as follows:

- The installation and operation of Boiler 12 does not violate any applicable requirements contained within the existing Title V permit (nor the TBD revised version of the Title V permit).
- The requested revisions do not involve significant changes to existing monitoring, reporting, or recordkeeping requirements in the permit. While the Title V permit will add additional requirements from 401 KAR 59:015 and NSPS Db, those conditions are considered state- and federally-enforceable monitoring, reporting, and recordkeeping requirements.
- This permit action does not require or change a case-by-case determination of an emission limit, a source-specific determination for temporary sources, or a visibility or increment analysis. No PSD avoidance limits are necessary for the Boiler 12 project. The annual potential emissions of all regulated NSR pollutants from the new boiler are below major source thresholds as demonstrated by Table 1. Besides making an administrative change to include Boiler 12 within the list of emissions units that are subject to the facility-wide emissions limits, as well as the limits for the collection of fossil fuel boilers, the federally-enforceable emissions limits will remain unchanged after the project.
- This permit action does not seek to establish or change a permit term or condition for which there is no corresponding underlying applicable requirement, and which the source has assumed to avoid an otherwise applicable requirement. The requested permit revisions correspond to applicable requirements of 401 KAR 59:015 and NSPS Db. The new emission unit satisfies the PM and $SO_2$ emissions limits of 401 KAR 59:015 through the use of good air pollution control practices and firing only natural gas. Furthermore, Boiler 12 satisfies the $NO_X$ limit of NSPS Db through the implementation of LNB and an FGR system and demonstrates compliance with this limit through the operation of a $NO_X$ CEMS.
- This permit action is not a modification under Title I of the Clean Air Act as this term is defined at 401 KAR 52:001 Section 1(52). Kentucky's Title V permitting rules defines modification under

> Title I of the Act as “a change at a facility that would constitute a modification under 42 USC 7470 to 7492 or 42 USC 7501 to 7515.” This includes PSD and NA-NSR modifications but does not include NSPS or NESHAP modifications. The proposed project does not trigger PSD review, and thus, is not considered a modification under Title I of the Act.

This application package provides information required under 401 KAR 52:020, Sections 4 and 5 for this purpose. The appropriate DEP7007 forms (AI, A, N, and V) covering the Boiler 12 project are provided in **Attachment A**.

Based on the analysis of the minor permit revision criteria in accordance with 401 KAR 52:020, Section 14(1), BTD has determined that the permit action qualifies for processing by KDAQ as a minor permit revision. This declaration is affirmed by BTD’s responsible official via the signature on the DEP7007AI form in **Attachment A**. Through this letter and application, BTD requests use of these procedures and this application package provides information required under 401 KAR 52:020, Section 14(3) for this purpose. A DEP7007AI form is provided in **Attachment A** to facilitate processing of this permit application.

### *Timing of Changes*

Section 14(4) of 401 KAR 52:020 allows an applicant to proceed with the proposed modifications upon filing of an administratively complete minor revision application. In response to the Title V renewal/Boiler 12 application, KDAQ granted approval for the construction and operation of Boiler 12 on June 29, 2018. As discussed with KDAQ in a meeting on June 5, 2019, BTD has installed and begun operation of Boiler 12 in January 2019; however, applicable requirements for this unit have not yet been incorporated into the operating permit. BTD is submitting this updated revision application to ensure that the administrative requirements for the Boiler 12 permit application are satisfied and to cooperatively work with KDAQ to develop appropriate permit language for the new boiler.

# ATTACHMENT A

## DEP7007 Forms (AI, A, N, and V)

Division for Air Quality

300 Sower Boulevard

Frankfort, KY 40601

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# DEP7007AI

## Administrative Information

___ Section AI.1: Source Information

___ Section AI.2: Applicant Information

___ Section AI.3: Owner Information

___ Section AI.4: Type of Application

___ Section AI.5: Other Required Information

___ Section AI.6: Signature Block

___ Section AI.7: Notes, Comments, and Explanations

**Additional Documentation**

___ Additional Documentation attached

| | |
|---|---|
| **Source Name:** | **Buffalo Trace Distillery, Inc.** |
| **KY EIS (AFS) #:** | **21-073-00009** |
| **Permit #:** | **V-12-056** |
| **Agency Interest (AI) ID:** | **1373** |
| **Date:** | **9/24/2019** |

## Section AI.1: Source Information

| | | | | | | |
|---|---|---|---|---|---|---|
| **Physical Location Address:** | **Street:** | 113 Great Buffalo Trace | | | | |
| | **City:** | Frankfort | **County:** | Franklin | **Zip Code:** | 40601 |
| **Mailing Address:** | **Street or P.O. Box:** | *Same as physical address* | | | | |
| | **City:** | | **State:** | | **Zip Code:** | |

**Standard Coordinates for Source Physical Location**

**Longitude:** -84.871° E (decimal degrees) **Latitude:** 38.216694° N (decimal degrees)

**Primary (NAICS) Category:** Distilleries **Primary NAICS #:** 312140

| | | | | |
|---|---|---|---|---|
| **Classification (SIC) Category:** | Distilled and Blended Liquors | **Primary SIC #:** | 2085 | |

**Briefly discuss the type of business conducted at this site:**

The site produces distilled spirits. Grain is delivered, ground, and introduced to mash cookers. The mash is fed to fermenters and then to distillation columns and condensers. The resulting liquid is stored in tanks, transferred to barrels for aging, and/or sent to the bottling area for packaging. Barrels of bourbon are stored in rick houses for aging. The spent grain is sold as distiller's dried grain. Beverage ingredients are received in bulk for blending, and other distilled spirits are received by the facility in bulk and sent to the bottling area for packaging.

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Description of Area Surrounding Source:** | ☐ Rural Area | ☐ Industrial Park | ☐ Residential Area | **Is any part of the source located on federal land?** | ☐ Yes | **Number of Employees:** | 474 |
| | ☐ Urban Area | ☐ Industrial Area | ☑ Commercial Area | | ☑ No | | |

| | | | | | |
|---|---|---|---|---|---|
| **Approximate distance to nearest residence or commercial** | *Adjacent* | **Property Area:** | 430 Acres | **Is this source portable?** | ☐ Yes ☑ No |

**What other environmental permits or registrations does this source currently hold or need to obtain in Kentucky?**

| | | | |
|---|---|---|---|
| **NPDES/KPDES:** | ☑ Currently Hold | ☐ Need | ☐ N/A |
| **Solid Waste:** | ☐ Currently Hold | ☐ Need | ☑ N/A |
| **RCRA:** | ☐ Currently Hold | ☐ Need | ☑ N/A |
| **UST:** | ☐ Currently Hold | ☐ Need | ☑ N/A |

| | | | | |
|---|---|---|---|---|
| **Type of Regulated Waste Activity:** | ☐ Mixed Waste Generator | ☑ Generator | ☐ Recycler | ☐ Other: ______________ |
| | ☐ U.S. Importer of Hazardous Waste | ☐ Transporter | ☐ Treatment/Storage/Disposal Facility | ☐ N/A |

## Section AI.2: Applicant Information

**Applicant Name:** Buffalo Trace Distillery

**Title:** (if individual)

**Mailing Address:**
**Street or P.O. Box:** 113 Great Buffalo Trace
**City:** Frankfort **State:** KY **Zip Code** 40601

**Email:** (if individual)

**Phone:** (502) 223-7641

**Technical Contact**

ENVIRONMENTAL AUDIT REPORT: PRIVILEGED DOCUMENT

**Name:** Andrew Leet

**Title:** Environmental Engineer

**Mailing Address:**
**Street or P.O. Box:** 113 Great Buffalo Trace
**City:** Frankfort **State:** KY **Zip Code** 40601

**Email:** aleet@buffalotrace.com

**Phone:** (859) 705-8187

**Air Permit Contact for Source**

**Name:** Andrew Leet

**Title:** Environmental Engineer

**Mailing Address:**
**Street or P.O. Box:** 113 Great Buffalo Trace
**City:** Frankfort **State:** KY **Zip Code** 40601

**Email:** aleet@buffalotrace.com

**Phone:** (859) 705-8187

## Section AI.3: Owner Information

☑ **Owner same as applicant**

**Name:** ______

**Title:** ______

**Mailing Address:** **Street or P.O. Box:** ______
**City:** ______ **State:** ______ **Zip Code:** ______

**Email:** ______

**Phone:** ______

**List names of owners and officers of the company who have an interest in the company of 5% or more.**

| Name | Position |
|---|---|
| Wholly-owned subsidiary of the Sazerac Company; New Orleans, LA | |
| | |
| | |

## Section AI.4: Type of Application

**Current Status:** ☑ Title V ☐ Conditional Major ☐ State-Origin ☐ General Permit ☐ Registration ☐ None

**Requested Action:**
*(check all that apply)*

| | | | |
|---|---|---|---|
| ☐ Name Change | ☐ Initial Registration | ☐ Significant Revision | ☐ Administrative Permit Amendment |
| ☐ Renewal Permit | ☐ Revised Registration | ☑ Minor Revision | ☐ Initial Source-wide OperatingPermit |
| ☐ 502(b)(10)Change | ☐ Extension Request | ☑ Addition of New Facility | ☐ Portable Plant Relocation Notice |
| ☐ Revision | ☐ Off Permit Change | ☐ Landfill Alternate Compliance Submittal | ☐ Modification of Existing Facilities |
| ☐ Ownership Change | ☐ Closure | | |

**Requested Status:** ☑ Title V ☐ Conditional Major ☐ State-Origin ☐ PSD ☐ NSR ☐ Other: ____________

**Is the source requesting a limitation of potential emissions?** ☐ Yes ☑ No

| **Pollutant:** | **Requested Limit:** | **Pollutant:** | **Requested Limit:** |
|---|---|---|---|
| ☐ Particulate Matter | | ☐ Single HAP | |
| ☐ Volatile Organic Compounds (VOC) | | ☐ Combined HAPs | |
| ☐ Carbon Monoxide | | ☐ Air Toxics (40 CFR 68, Subpart F) | |
| ☐ Nitrogen Oxides | | ☐ Carbon Dioxide | |
| ☐ Sulfur Dioxide | | ☐ Greenhouse Gases (GHG) | |
| ☐ Lead | | ☐ Other | |

**For New Construction:**

**Proposed Start Date of Construction:** *(MM/YYYY)* 08/2018

**Proposed Operation Start-Up Date:** *(MM/YYYY)* 01/2019

**For Modifications:**

**Proposed Start Date of Modification:** *(MM/YYYY)* ____________

**Proposed Operation Start-Up Date:** *(MM/YYYY)* ____________

**Applicant is seeking coverage under a permit shield.** ☐ **Yes** ☑ **No**

**Identify any non-applicable requirements for which permit shield is sought on a separate attachment to the application.**

## Section AI.5 Other Required Information

**Indicate the documents attached as part of this application:**

- ☑ DEP7007A Indirect Heat Exchangers and Turbines
- ☐ DEP7007B Manufacturing or Processing Operations
- ☐ DEP7007C Incinerators and Waste Burners
- ☐ DEP7007F Episode Standby Plan
- ☐ DEP7007J Volatile Liquid Storage
- ☐ DEP7007K Surface Coating or Printing Operations
- ☐ DEP7007L Mineral Processes
- ☐ DEP7007M Metal Cleaning Degreasers
- ☑ DEP7007N Source Emissions Profile
- ☐ DEP7007P Perchloroethylene Dry Cleaning Systems
- ☐ DEP7007R Emission Offset Credit
- ☐ DEP7007S Service Stations
- ☐ DEP7007T Metal Plating and Surface Treatment Operations
- ☑ DEP7007V Applicable Requirements and Compliance Activities
- ☐ DEP7007Y Good Engineering Practice and Stack Height Determination
- ☐ DEP7007AA Compliance Schedule for Non-complying Emission Units
- ☐ DEP7007BB Certified Progress Report
- ☐ DEP7007CC Compliance Certification
- ☐ DEP7007DD Insignificant Activities
- ☐ DEP7007EE Internal Combustion Engines
- ☐ DEP7007FF Secondary Aluminum Processing
- ☐ DEP7007GG Control Equipment
- ☐ DEP7007HH Haul Roads
- ☐ Confidentiality Claim
- ☐ Ownership Change Form
- ☐ Secretary of State Certificate
- ☐ Flowcharts or diagrams depicting process
- ☐ Digital Line Graphs (DLG) files of buldings, roads, etc.
- ☐ Site Map
- ☐ Map or drawing depicting location of facility
- ☐ Safety Data Sheet (SDS)
- ☐ Emergency Response Plan
- ☐ Other: ____________________

## Section AI.6: Signature Block

**I, the undersigned, hereby certify under penalty of law, that I am a responsible official*, and that I have personally examined, and am familiar with, the information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the information is on knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false or incomplete information, including the possibility of fine or imprisonment.**

Harlen Wheatley

**Authorized Signature**

9/23/2019

**Date**

Harlen Wheatley

**Type or Printed Name of Signatory**

Master Distiller

**Title of Signatory**

*Responsible official as defined by 401 KAR 52:001.

| Section AI.7: Notes, Comments, and Explanations |
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Division for Air Quality

300 Sower Boulevard

Frankfort, KY 40601

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# DEP7007A

## Indirect Heat Exchangers and Turbines

___ Section A.1: General Information

___ Section A.2: Operating and Fuel Information

___ Section A.3: Notes, Comments, and Explanations

**Additional Documentation**

___ Complete DEP7007AI, DEP7007N, DEP7007V, and DEP7007GG.

____ Manufacturer's specifications

**Source Name:** Buffalo Trace Distillery, Inc.

**KY EIS (AFS) #:** 21-073-00009

**Permit #:** V-12-056

**Agency Interest (AI) ID:** 1373

**Date:** 9/24/2019

## Section A.1: General Information

| Emission Unit # | Emission Unit Name | Process ID | Process Name | Identify General Type: Indirect Heat Exchanger, Gas Turbine, or Combustion Turbine | Indirect Heat Exchanger Configuration | Manufacturer | Model No./ Serial No. | Proposed/Actual Date of Construction Commencement *(MM/YYYY)* | SCC Code | SCC Units | Control Device ID | Stack ID |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 16 | BOILER 12 | 01 | NATURAL GAS COMBUSTION | INDIRECT HEAT EXCHANGER | Industrial Watertube Boiler | CLEAVER BROOKS | NCB-300-G6B--O00-W100B-S9/ N20322 & SP-NB-501D-100/ SP-4539 | 12/2018 | 10200601 | MMscf | NA | S16 |
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## Section A.2: Operating and Fuel Information

| Emission Unit # | If multipurpose unit, identify the percentage of use by purpose | | | | Rated Capacity Heat Input *(MMBTU/hr)* | Rated Capacity Power Output | | Describe Operating Scenario (only if this unit will be used in different configurations) | Classify Fuel as Primary or Secondary | Identify Fuel Type: Coal, Natural Gas, Wood, Biomass, Landfill/Digester Gas, Fuel Oil # (specify 1-6), or Other | Heat Content (HHV) | | Maximum Operating Hours | Ash Content *(%)* | Sulfur Content *(%)* |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Space Heat | Process Heat | Power | Emergency | | | *(Specify units: hp, MW, or lb steam/hr)* | | | | | *(Specify units: Btu/lb, Btu/gal, or Btu/scf)* | | | |
| 16 | | | | | 179.2 | 150,000 | lb/hr | | Primary | Natural Gas | 1020 | Btu/scf | 8760 | N/A | N/A |
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| Section A.3: Notes, Comments, and Explanations |
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Division for Air Quality

300 Sower Boulevard
Frankfort, KY 40601
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# DEP7007N

## Source Emissions Profile

__ Section N.1: Emission Summary
__ Section N.2: Stack Information
__ Section N.3: Fugitive Information
__ Section N.4: Notes, Comments, and Explanations

**Additional Documentation**

___ Complete DEP7007AI

**Source Name:** Buffalo Trace Distillery, Inc.
**KY EIS (AFS) #:** 21-073-00009
**Permit #:** V-12-056
**Agency Interest (AI) ID:** 1373
**Date:** 9/24/2019

## N.1: Emission Summary

| Emission Unit # | Emission Unit Name | Process ID | Process Name | Control Device Name | Control Device ID | Stack ID | Maximum Design Capacity (SCC Units/hour) | Pollutant | Uncontrolled Emission Factor (lb/SCC Units) | Emission Factor Source (e.g. AP-42, Stack Test, Mass Balance) | Capture Efficiency (%) | Control Efficiency (%) | Hourly Emissions: Uncontrolled Potential (lb/hr) | Hourly Emissions: Controlled Potential (lb/hr) | Annual Emissions: Uncontrolled Potential (tons/yr) | Annual Emissions: Controlled Potential (tons/yr) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 16 | BOILER 12 | 01 | NATURAL GAS COMBUSTION | NA | NA | S16 | 0.1757 | PM | 7.60 | AP-42 Section 1.4 Table 1.4-2 (7/98) | 100.00% | 0.00% | 1.34 | 1.34 | 5.85 | 5.85 |
| | | | | | | | | PM10 | 7.60 | AP-42 Section 1.4 Table 1.4-2 (7/98) | 100.00% | 0.00% | 1.34 | 1.34 | 5.85 | 5.85 |
| | | | | | | | | PM2.5 | 7.60 | AP-42 Section 1.4 Table 1.4-2 (7/98) | 100.00% | 0.00% | 1.34 | 1.34 | 5.85 | 5.85 |
| | | | | | | | | SO2 | 0.600 | AP-42 Section 1.4 Table 1.4-2 (7/98) | 100.00% | 0.00% | 0.105 | 0.105 | 0.462 | 0.462 |
| | | | | | | | | NOx | 37.1 | Vendor Estimate | 100.00% | 0.00% | 6.52 | 6.52 | 28.6 | 28.6 |
| | | | | | | | | CO | 84.0 | AP-42 Section 1.4 Table 1.4-1 (7/98) | 100.00% | 0.00% | 14.8 | 14.8 | 64.6 | 64.6 |
| | | | | | | | | VOC | 5.50 | AP-42 Section 1.4 Table 1.4-2 (7/98) | 100.00% | 0.00% | 0.966 | 0.966 | 4.23 | 4.23 |
| | | | | | | | | CO2 | 119,317 | EPA's GHG Reporting Rule (40 CFR 98), Table C-1 | 100.00% | 0.00% | 20,962 | 20,962 | 91,815 | 91,815 |
| | | | | | | | | CH4 | 2.25 | EPA's GHG Reporting Rule (40 CFR 98), Table C-2 | 100.00% | 0.00% | 0.395 | 0.395 | 1.73 | 1.73 |
| | | | | | | | | N2O | 0.225 | EPA's GHG Reporting Rule (40 CFR 98), Table C-2 | 100.00% | 0.00% | 0.040 | 0.040 | 0.173 | 0.173 |
| | | | | | | | | CO2e | 119,440 | Scaled each pollutant by GWP | 100.00% | 0.00% | 20,984 | 20,984 | 91,910 | 91,910 |
| | | | | | | | | Total HAPs | 1.89 | Sum of HAPs, AP-42 Section 1.4 Table 1.4-3 (7/98) | 100.00% | 0.00% | 0.332 | 0.332 | 1.45 | 1.45 |

## Section N.2: Stack Information

### UTM Zone:

| Stack ID | Identify all Emission Units (with Process ID) and Control Devices that Feed to Stack | Stack Physical Data | | | Stack UTM Coordinates | | Stack Gas Stream Data | | |
|---|---|---|---|---|---|---|---|---|---|
| | | Equivalent Diameter *(ft)* | Height *(ft)* | Base Elevation *(ft)* | Northing *(m)* | Easting *(m)* | Flowrate *(acfm)* | Temperature *(°F)* | Exit Velocity *(ft/sec)* |
| S16 | 16 | 4.5 | 65.1 | 505 | 4,231,873 | 686,300 | 52,524 | 302 | 55 |
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## Section N.3: Fugitive Information

**UTM Zone:**

| Emission Unit # | Emission Unit Name | Process ID | Area Physical Data | | Area UTM Coordinates | | Area Release Data | |
|---|---|---|---|---|---|---|---|---|
| | | | Length of the X Side *(ft)* | Length of the Y Side *(ft)* | Northing *(m)* | Easting *(m)* | Release Temperature *(°F)* | Release Height *(ft)* |
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| Section N.4: Notes, Comments, and Explanations |
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Division for Air Quality

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# DEP7007V

## Applicable Requirements and Compliance Activities

___ Section V.1: Emission and Operating Limitation(s)
___ Section V.2: Monitoring Requirements
___ Section V.3: Recordkeeping Requirements
___ Section V.4: Reporting Requirements
___ Section V.5: Testing Requirements
___ Section V.6: Notes, Comments, and Explanations

**Additional Documentation**

___ Complete DEP7007AI

**Source Name:** **Buffalo Trace Distillery, Inc.**
**KY EIS (AFS) #:** **21-073-00009**
**Permit #:** **V-12-056**
**Agency Interest (AI) ID:** **1373**
**Date:** **9/24/2019**

## Section V.1: Emission and Operating Limitation(s)

| Emission Unit # | Emission Unit Description | Applicable Regulation or Requirement | Pollutant | Emission Limit (if applicable) | Voluntary Emission Limit or Exemption (if applicable) | Operating Requirement or Limitation (if applicable) | Method of Determining Compliance with the Emission and Operating Requirement(s) |
|---|---|---|---|---|---|---|---|
| 16 | BOILER 12 | 401 KAR 59:015 | PM | 0.10 lb/MMBtu | N/A | Particulate matter emissions shall not exceed the limit determined under Section 4 of this regulation. | Equipment design and use of natural gas as fuel. |
| 16 | BOILER 12 | 401 KAR 59:015 | SO2 | 0.8 lb/MMBtu | N/A | Sulfur dioxide emissions shall not exceed the limit determined under Section 5 of this regulation. | Equipment design and use of natural gas as fuel. |
| 16 | BOILER 12 | 401 KAR 59:015 | Opacity | 20 Percent (with exceptions) | N/A | Opacity shall not exceed the limits under Section 4 of this regulation, with exceptions noted. | Equipment design and use of natural gas as fuel; periodic visible emissions observations. |

| Emission Unit # | Emission Unit Description | Applicable Regulation or Requirement | Pollutant | Emission Limit (if applicable) | Voluntary Emission Limit or Exemption (if applicable) | Operating Requirement or Limitation (if applicable) | Method of Determining Compliance with the Emission and Operating Requirement(s) |
|---|---|---|---|---|---|---|---|
| 16 | BOILER 12 | 40 CFR 60.42b(k)(2) | SO2 | 0.32 lb/MMBtu | N/A | Provided that potential SO2 emissions are less than 0.32 lb/MMBtu, source is exempt from NSPS Db SO2 limit. | Fuel receipts (e.g., current, valid purchase contract; tariff sheet; or transportation contract) from the fuel supplier certifying that gaseous fuel meets the definition of natural gas and the applicable sulfur limit. |
| 16 | BOILER 12 | 40 CFR 60.44b(a) | NOx | 0.20 lb/MMBtu | N/A | Compliance determined on 30-day rolling average basis using CEMS or PEMS | Use of NOx/O2 CEMS results compiled into 30 day rolling averages |
| 16 | BOILER 12 | 401 KAR 59:015, Section 7 | N/A | N/A | N/A | During startup or shutdowns, comply with the work practice standards established in this section. | Document startups/shutdowns and actions taken by signed contemporaneous logs or other relevant evidence. |
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## Section V.2: Monitoring Requirements

| Emission Unit # | Emission Unit Description | Pollutant | Applicable Regulation or Requirement | Parameter Monitored | Description of Monitoring |
|---|---|---|---|---|---|
| 16 | BOILER 12 | N/A | 40 CFR 60.49b(d)(2) | Natural Gas Usage | Use fuel flow meters and/or natural gas utility bills to monitor natural gas usage in the boiler on a monthly basis. |
| 16 | BOILER 12 | NOx | 40 CFR 60.48b(c)<br>40 CFR 60.48b(e)(2)(i) | NOx/O2 Concentration | Install, calibrate, maintain, and operate Continuous Emissions Monitoring System (CEMS) for measuring NOx and O2. |
| 16 | BOILER 12 | NOx | 40 CFR 60.46b(e)(1) | NOx Emissions (lb/MMBtu basis) | Monitor NOx emissions (lb/MMBtu basis) for 30 successive steam generating unit operating days to demonstrate initial compliance with limit. The 30-day average emission rate is calculated as the average of all hourly emissions data recorded by the monitoring system during the 30-day test period. |
| 16 | BOILER 12 | NOx | 40 CFR 60.46b(e)(4) | NOx Emissions (lb/MMBtu basis) | Monitor 30-day rolling average NOx emissions (lb/MMBtu basis) for each steam generating unit operating day. The results should be used to prepare excess emission reports but <u>not</u> to determine compliance with standard. |
| 16 | BOILER 12 | NOx | 40 CFR 60.48b(b)(1) | NOx Emissions (lb/MMBtu basis) | Install, calibrate, maintain, and operate CEMS for measuring NOx and O2 (or CO2) emissions discharged to the atmosphere, and record the output of the system. |
| 16 | BOILER 12 | NOx | 40 CFR 60.48b(d) | NOx Emissions (lb/MMBtu basis) | Calculate the 1-hour averages using the data points required under 40 CFR 60.13(h)(2); express the 1-hour average NOx emission rates measured by the CEMS in ng/J or lb/MMBtu heat input and use the results to calculate the average emission rates for comparison to the standard. |
| 16 | BOILER 12 | NOx | 40 CFR 60.48b(f) | NOx Emissions (lb/MMBtu basis) | When CEMS data not obtained because of breakdowns, repairs, etc., obtain NOx emissions data using standby monitoring systems, Method 7 of appendix A of 40 CFR Part 60, Method 7A of appendix A of 40 CFR Part 60, or other approved reference methods to provide emission data for a minimum of 75 percent of the operating hours in each steam generating unit operating day, in at least 22 out of 30 successive steam generating unit operating days. |
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## Section V.3: Recordkeeping Requirements

| Emission Unit # | Emission Unit Description | Pollutant | Applicable Regulation or Requirement | Parameter Recorded | Description of Recordkeeping |
|---|---|---|---|---|---|
| 16 | BOILER 12 | N/A | 40 CFR 60.49b(d)(2) | Natural Gas Usage | Record natural gas usage in the boiler on a monthly basis. |
| 16 | BOILER 12 | NOx | 40 CFR 60.48b(b)(1)<br>40 CFR 60.48b(c) | NOx/O2 Concentration | Record the output of the CEMS for NOx and O2 at all times of boiler operation, except for CEMS breakdowns and repairs. |
| 16 | BOILER 12 | NOx | 40 CFR 60.13(h)(2) | Daily NOx Emissions (lb/MMBtu basis) | Record NOx emissions (lb/MMBtu basis) for each steam generating unit operating day using CEMS data points required under this regulation. |
| 16 | BOILER 12 | NOx | 40 CFR 60.44b(i) | 30-Day Rolling Average NOx Emissions (lb/MMBtu basis) | Record 30-day rolling average NOx emissions (lb/MMBtu basis) calculated from daily NOx emissions. The results should be used to prepare excess emission reports but not to determine compliance with standard. |
| 16 | BOILER 12 | NOx | 40 CFR 60, Appendix F | Quality Assurance Plan (QAP) | Establish a written QAP that details step-by-step procedures and operations for the following activities:<br>- CEMS calibration;<br>- Calibration drift determination and resulting CEMS adjustment;<br>- Preventative maintenance of the CEMS, including a spare parts inventory reflecting the spare parts maintained on-site by BT;<br>- Data recording, calculation, and reporting procedures;<br>- Accuracy audit procedures including sampling and analysis methods; and<br>- Program of corrective actions if the CEMS malfunctions. |
| 16 | BOILER 12 | NOx | 40 CFR 60, Appendix B & F | CEMS QA/QC documentation | In conformance with QAP plan, record the following:<br>- Results of daily calibration drift checks and associated CEMS adjustments;<br>- Results of annual RATAs;<br>- Results of quarterly Cylinder Gas Audits (CGAs); and<br>- Preventative maintenance of CEMS. |
| 16 | BOILER 12 | N/A | 401 KAR 59:015, Section 7 | Startup/Shutdown logs | Document the actions, including duration of the startup period, during startup period and shutdown periods by signed, contemporaneous logs or other relevant evidence. |
| 16 | BOILER 12 | NOx | 40 CFR 60.49b(g) | Daily Operating Information | Maintain records of data required under this section for each steam generating unit operating day. |
| 16 | BOILER 12 | SO2 | 40 CFR 60.49b(r)(1) | Fuel Receipts | Maintain fuel receipts (such as a current, valid purchase contract, tariff sheet, or transportation contract) from the fuel supplier that certify that the fuel meets the definition of natural gas as defined in §60.41b and the applicable sulfur limit (0.32 lb/MMBtu). |
| | | | | | |

## Section V.4: Reporting Requirements

| Emission Unit # | Emission Unit Description | Pollutant | Applicable Regulation or Requirement | Parameter Reported | Description of Reporting |
|---|---|---|---|---|---|
| 16 | BOILER 12 | SO2 | 40 CFR 60.49b(r)(1) | Fuel Types Used during Reporting Period | In semiannual monitoring reports (SAMRs), certify that only natural gas was used in Boiler 12. |
| 16 | BOILER 12 | NOx | 40 CFR 60.49b(g)<br>40 CFR 60.49b(i)<br>40 CFR 60.49b(w) | NOx Emissions and Related Information | In each SAMR, report the following information for Boiler 12:<br>- Average hourly NOx emission rate (lb/MMBtu basis);<br>- 30-day average NOx emission rate (lb/MMBtu basis);<br>- Identify days when calculated NOx in excess of standard;<br>- Identify days when emissions data not obtained or excluded, with reasons for this treatment;<br>- F-factor used in calculation;<br>- Times when the NOx concentration exceeded the full span of the CEMS;<br>- Changes to CEMS that could impact compliance with PS 2; and<br>- Results of daily drift checks and quarterly CGAs. |
| 16 | BOILER 12 | N/A | 40 CFR 60.49b(a)<br>40 CFR 60.7 | Startup | File startup notifications in accordance with 40 CFR 60 Subpart A requirements. |
| 16 | BOILER 12 | NOx | 40 CFR 60.49b(b) | RATA Results | Report results of initial and subsequent annual RATAs. |
| 16 | BOILER 12 | NOx | 40 CFR 60.49b(b) | Initial Compliance Demonstration | Report results of initial compliance demonstration, which tracked NOx emissions (lb/MMBtu basis) for 30 successive steam generating unit operating days to demonstrate initial compliance with limit. |
| 16 | BOILER 12 | NOx | 40 CFR 60.49b(h) | Excess Emissions | Submit excess emissions reports if any 30-day rolling average result exceeds applicable NOx standard. |
| 16 | BOILER 12 | NOx | 40 CFR 60.49b(c) | Plan for PEMS option (if CEMS not used) | If seeking to demonstrate compliance with the NOx standard through the monitoring of steam generating unit operating conditions in the provisions of 40 CFR 60.48b(g)(2) (i.e., Predictive Emissions Monitoring System - PEMS), submit for approval a plan that identifies the operating conditions to be monitored and the records to be maintained. |
| | | | | | |

## Section V.5: Testing Requirements

| Emission Unit # | Emission Unit Description | Pollutant | Applicable Regulation or Requirement | Parameter Tested | Description of Testing |
|---|---|---|---|---|---|
| 16 | BOILER 12 | NOx | 40 CFR 60.46b(e) | NOx/O2 Concentration | To determine compliance with NOx limit, conduct the performance test as required under §60.8 using the NOx CEMS. |
| 16 | BOILER 12 | NOx | 40 CFR 60.48b(e)<br>40 CFR 60.13<br>40 CFR 60, Appendix B | NOx/O2 Concentration | Follow the procedures of 40 CFR 60.13 for installation, evaluation, and operation of the CEMS. This includes completion of an initial and annual Relative Accuracy Test Audit (RATA), daily drift checks, and quarterly cylinder gas audits. |
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| Section V.6: Notes, Comments, and Explanations |
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# ATTACHMENT B

## Supporting Emission Calculations

# B-1. Supporting Emission Calculations for Boiler 12 (EU ID 16)

## B-1.1 Boiler Duty and Fuel Consumption Data

| Boiler Operating Information | Value | Units | Basis |
|---|---|---|---|
| Rated Heat Input Capacity | 179.2 | MMBtu/hr | Title V permit renewal application and revision request, dated 2/12/2018 |
| Maximum Fuel Usage | 0.176 | MMscf/hr | = 179.2 MMBtu/hr / 1020 Btu/scf |
| Hours Restriction | 8,760 | hrs/yr | Continuous annual operations |

### B-1.1.1 Constants and Conversion Factors

| Constants | Value | Units | Basis |
|---|---|---|---|
| Heating Value of NG | 1,020 | Btu/scf | Standard HHV from AP-42 Section 1.4; used in Title V renewal application |
| Molar Volume (at STP) | 385.5 | scf/lbmol | = 528 oR / 1 atm x 0.7302 cf-atm/(lbmol-oR) |
| Standard Temperature | 68 | $^{o}F$ | STP Parameters |
| | 528 | $^{o}R$ | |
| Stack Temperature | 302 | $^{o}F$ | Supplied by vendor |
| | 762 | $^{o}R$ | |
| Standard Pressure | 1 | atm | STP Parameters |
| Universal Gas Constant | 0.7302 | cf-atm/(lbmol-$^{o}$R) | Constant |
| Molecular Weights | 46.01 | lb NO2/lbmol | Constant |
| | 28.01 | lb CO/lbmol | Constant |
| F-Factor | 8,710 | dscf/MMBtu | F-Factor for natural gas combustion from 40 CFR 60, Appendix A (Method 19) |
| Flow Rate | 26,014 | dscf/min | Calculated based on F-Factor (0% O2) |
| | 37,543 | acfm | Calculated at 0% O2, dry |
| | 43,835 | acfm | Calculated at 3% O2, dry |
| | 52,524 | acfm | Supplied by vendor |

## B-1.1 Emission Factor Basis

### B-1.1.1 Vendor Data

| Pollutant | CAS # | Concentration (ppmv @ 3%,O2) | Concentration (ppmv @ 0%,O2) | Emission Factor Basis |
|---|---|---|---|---|
| NOx | na | 30 | 35 | Vendor estimate for boiler with Low NOx Burners (LNB) and Flue Gas Recirculation (FGR) firing at high fire (100% load); exhaust expressed at 3% oxygen concentration, corrected to 0% oxygen concentration by multiplying by 20.9% / (20.9% - 3%) |

### B-1.1.2 Criteria Pollutants Emission Factors

| Pollutant | CAS # | Emission Factor (lb/MMBtu) | Emission Factor (lb/MMscf) | Emission Factor Basis |
|---|---|---|---|---|
| PM | na | 0.0075 | 7.6 | AP-42 Section 1.4 Table 1.4-2 (7/98) |
| PM-CON = PM10-CON = PM25-CON | na | 0.0056 | 5.7 | AP-42 Section 1.4 Table 1.4-2 (7/98) |
| PM-FIL | na | 0.0019 | 1.9 | AP-42 Section 1.4 Table 1.4-2 (7/98) |
| PM10 | na | 0.0075 | 7.6 | PM = PM10 |
| PM10-FIL | na | 0.0019 | 1.9 | PM = PM10 |
| PM2.5 | na | 0.0075 | 7.6 | PM = PM2.5 |
| PM2.5-FIL | na | 0.0019 | 1.9 | PM = PM2.5 |
| SO2 | 07446-09-5 | 0.0006 | 0.60 | AP-42 Section 1.4 Table 1.4-2 (7/98) |
| NOx | 10102-44-0 | 0.0364 | 37.1 | Vendor estimate for boiler with LNB and FGR (ThermalTech Engineering) |
| CO | 00630-08-0 | 0.0824 | 84.0 | AP-42 Section 1.4 Table 1.4-1 (7/98) |
| VOC | na | 0.0054 | 5.50 | AP-42 Section 1.4 Table 1.4-2 (7/98) |

B-1.1.3 HAP Emission Factors

> Emission factors for organic HAP compounds expected to be emitted are based on emission factors in AP-42 Table 3.3-2 (10/96 Edition).

| Pollutant | CAS # | Emission Factor (lb/MMBtu) | Emission Factor (lb/MMscf) | Emission Factor Basis |
|---|---|---|---|---|
| Benzene | 00071-43-2 | 2.1E-06 | 2.1E-03 | AP-42 Section 1.4 Table 1.4-3 (7/98) |
| Dichlorobenzene | 00095-50-1 | 1.2E-06 | 1.2E-03 | |
| Formaldehyde | 00050-0-0 | 7.4E-05 | 7.5E-02 | |
| Hexane | 00110-54-3 | 0.0018 | 1.8 | |
| Naphthalene | 00091-20-3 | 6.0E-07 | 6.1E-04 | |
| Toluene | 00108-88-3 | 3.3E-06 | 3.4E-03 | |
| Sum of POMs | na | 8.6E-08 | 8.8E-05 | |
| Arsenic | 07440-38-2 | 2.0E-07 | 2.0E-04 | |
| Cadmium | 07440-43-9 | 1.1E-06 | 1.1E-03 | |
| Chromium | 07440-47-3 | 1.4E-06 | 1.4E-03 | |
| Cobalt | 07440-48-4 | 8.2E-08 | 8.4E-05 | |
| Manganese | 07439-96-5 | 3.7E-07 | 3.8E-04 | |
| Mercury | 07439-97-6 | 2.5E-07 | 2.6E-04 | |
| Nickel | 07440-02-0 | 2.1E-06 | 2.1E-03 | |
| Selenium | 07782-49-2 | 2.4E-08 | 2.4E-05 | |
| Lead | 07439-92-1 | 4.9E-07 | 5.0E-04 | |
| Total HAP | | | 1.888 | |

B-1.1.4 GHG Emission Factors

> CO2, CH4 and N2O emissions for diesel fuel combustion are estimated using the natural gas emission factors published in AP-42 Section 1.4.

Global Warming Potentials (GWP) of GHGs per 40 CFR 98 Subpart A, Table A-1.

| | |
|---|---|
| CO2 | 1 |
| CH4 | 25 |
| N2O | 298 |

| Pollutant | CAS # | Emission Factor (lb/MMBtu) | Emission Factor (lb/MMscf) | Emission Factor Basis |
|---|---|---|---|---|
| CO2 | 00124-38-9 | 117 | 119,317 | EPA's GHG Reporting Rule (40 CFR 98), Table C-1 |
| CH4 | 00074-82-8 | 2.2E-03 | 2.25 | EPA's GHG Reporting Rule (40 CFR 98), Table C-2 |
| N2O | 10024-97-2 | 2.2E-04 | 0.225 | EPA's GHG Reporting Rule (40 CFR 98), Table C-2 |
| CO2e | na | -- | 119,440 | Scaled each pollutant by GWP |

## B-1.2 Potential Emissions from Boiler 12 Installation Project

| | Uncontrolled Emission Factor Value | Units | Uncontrolled Emissions (lb/hr) | (tpy) | Control Efficiency | PTE (tpy) |
|---|---|---|---|---|---|---|
| **Primary Pollutants** | | | | | | |
| PM | 7.60 | lb/MMscf | 1.34 | 5.85 | na | 5.85 < 25 tpy |
| PM-CON | 5.70 | lb/MMscf | 1.00 | 4.39 | na | 4.39 |
| PM-FIL | 1.90 | lb/MMscf | 0.334 | 1.46 | na | 1.46 |
| PM10 | 7.60 | lb/MMscf | 1.34 | 5.85 | na | 5.85 < 15 tpy |
| PM10-FIL | 1.90 | lb/MMscf | 0.334 | 1.46 | na | 1.46 |
| PM2.5 | 7.60 | lb/MMscf | 1.34 | 5.85 | na | 5.85 < 10 tpy |
| PM2.5-FIL | 1.90 | lb/MMscf | 0.334 | 1.46 | na | 1.46 |
| SO2 | 0.600 | lb/MMscf | 0.105 | 0.462 | na | 0.462 < 40 tpy |
| NOx | 37.1 | lb/MMscf | 6.52 | 28.6 | na | 28.6 < 40 tpy |
| CO | 84.0 | lb/MMscf | 14.8 | 64.6 | na | 64.6 < 100 tpy |
| VOC | 5.50 | lb/MMscf | 0.966 | 4.23 | na | 4.23 < 40 tpy |
| CO2 | 119,317 | lb/MMscf | 20,962 | 91,815 | na | 91,815 |
| CH4 | 2.25 | lb/MMscf | 0.395 | 1.73 | na | 1.73 |
| N2O | 0.225 | lb/MMscf | 3.95E-02 | 0.173 | na | 0.173 |
| CO2e | 119,440 | lb/MMscf | 20,984 | 91,910 | na | 91,910 < 100,000 tpy |
| Total HAPs | 1.89 | lb/MMscf | 0.332 | 1.45 | na | 1.45 < 25 tpy |
| | | | | | | |
| **HAPs/metals** | | | | | | |
| Benzene | 2.10E-03 | lb/MMscf | 3.69E-04 | 1.62E-03 | na | 1.62E-03 |
| Dichlorobenzene | 1.20E-03 | lb/MMscf | 2.11E-04 | 9.23E-04 | na | 9.23E-04 |
| Formaldehyde | 7.50E-02 | lb/MMscf | 1.32E-02 | 5.77E-02 | na | 5.77E-02 |
| Hexane | 1.80 | lb/MMscf | 0.316 | 1.39 | na | 1.39 < 10 tpy |
| Naphthalene | 6.10E-04 | lb/MMscf | 1.07E-04 | 4.69E-04 | na | 4.69E-04 |
| Toluene | 3.40E-03 | lb/MMscf | 5.97E-04 | 2.62E-03 | na | 2.62E-03 |
| Sum of POMs | 8.82E-05 | lb/MMscf | 1.55E-05 | 6.79E-05 | na | 6.79E-05 |
| Arsenic | 2.00E-04 | lb/MMscf | 3.51E-05 | 1.54E-04 | na | 1.54E-04 |
| Cadmium | 1.10E-03 | lb/MMscf | 1.93E-04 | 8.46E-04 | na | 8.46E-04 |
| Chromium | 1.40E-03 | lb/MMscf | 2.46E-04 | 1.08E-03 | na | 1.08E-03 |
| Cobalt | 8.40E-05 | lb/MMscf | 1.48E-05 | 6.46E-05 | na | 6.46E-05 |
| Manganese | 3.80E-04 | lb/MMscf | 6.68E-05 | 2.92E-04 | na | 2.92E-04 |
| Mercury | 2.60E-04 | lb/MMscf | 4.57E-05 | 2.00E-04 | na | 2.00E-04 |
| Nickel | 2.10E-03 | lb/MMscf | 3.69E-04 | 1.62E-03 | na | 1.62E-03 |
| Selenium | 2.40E-05 | lb/MMscf | 4.22E-06 | 1.85E-05 | na | 1.85E-05 |
| Lead | 5.00E-04 | lb/MMscf | 8.78E-05 | 3.85E-04 | na | 3.85E-04 |

# ATTACHMENT C

## Suggested Permit Language

## SECTION B - EMISSION UNITS, EMISSION POINTS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

**Emissions Unit 16 (16-001) Indirect Heat Exchanger**

**Description:**

Natural gas fired indirect heat exchanger.
Maximum continuous rating: 179.2 MMBtu/hr
Construction commenced: 2018

**APPLICABLE REGULATIONS:**

401 KAR 59:015, New indirect heat exchangers

401 KAR 60:005 incorporated by reference 40 CFR 60, Subpart Db, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

**NON APPLICABLE REGULATIONS:**

40 CFR 63 Subpart JJJJJ – National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers at Area Sources

1. **Operating limitations:**

   a. During a startup period or shutdown period, the permittee shall comply with the work practice standards established in 401 KAR 59:015, Section 7: [401 KAR 59:015, Section 7]

      i. The permittee shall comply with 401 KAR 50:055, Section 2(5); [401 KAR 59:015, Section 7(1)(a)]

      ii. The frequency and duration of startup periods or shutdown periods shall be minimized by the affected facility; [401 KAR 59:015, Section 7(1)(b)]

      iii. All reasonable steps shall be taken by the permittee to minimize the impact of emissions on ambient air quality from the affected facility during startup periods and shutdown periods; [401 KAR 59:015, Section 7(1)(c)]

      iv. Startups and shutdowns shall be conducted according to either: [401 KAR 59:015, Section 7(1)(e)]

         1. The manufacturer's recommended procedures; or [401 KAR 59:015 Section 7(1)(e)1.]

         2. Recommended procedures for a unit of similar design, for which manufacturer's recommended procedures are available, as approved by the cabinet based on documentation provided by the permittee. [401 KAR 59:015, Section 7(1)(e)2.];

## SECTION B - EMISSION UNITS, EMISSION POINTS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

**Compliance Demonstration Method:**
Compliance shall be demonstrated according to 5. Specific Recordkeeping Requirements, paragraph a.

2. **Emission Limitations:**

a. PM emissions shall not exceed 0.10 lb/MMBtu actual heat input. [401 KAR 59:015, Section 4(1)(b)]

b. Opacity shall not exceed 20 percent except: [401 KAR 59:015, Section 4(2)]

i. A maximum of 27 percent opacity shall be allowed for one 6-minute period in any 60 consecutive minutes; and [401 KAR 59:015, Section 4(2)(a)]

ii. For emissions caused by building a new fire, emissions during the period required to bring the boiler up to operating conditions shall be allowed, if the method used is recommended by the manufacturer and the time does not exceed the manufacturer's recommendations. [401 KAR 59:015, Section 4(2)(c)]

c. $SO_2$ emissions shall not exceed 0.8 lb/MMBtu actual heat input. [401 KAR 59:015, Section 5(1)(b)1.]

**Compliance Demonstration Method:**
The unit is assumed to be in compliance with the 401 KAR 59:015 PM emissions, opacity, and $SO_2$ emissions standards while combusting natural gas.

d. Potential $SO_2$ emissions must be less than 0.32 lb/MMBtu to preclude the applicability of the $SO_2$ emission standard in 40 CFR 60, Subpart Db. [40 CFR 60.42b(k)(2)]

**Compliance Demonstration Method:**
Compliance shall be demonstrated according to 5. Specific Recordkeeping Requirements, paragraph c.

e. As a high heat release rate unit, $NO_X$ emissions shall not exceed 0.20 lb/MMBtu. The $NO_X$ standard shall apply at all times, including periods of startup, shutdown, or malfunction. [40 CFR 60.44b(a), 40 CFR 60.46b(a)]

**Compliance Demonstration Method:**
Compliance shall be demonstrated according to 3. Testing Requirements, paragraph b and 4. Monitoring Requirements, paragraphs b through f.

3. **Testing Requirements:**

a. Testing shall be conducted at such time as may be requested by the Cabinet in accordance with 401 KAR 59:005, Section 2 (2) and 401 KAR 50:045, Section (4).

## SECTION B - EMISSION UNITS, EMISSION POINTS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

b. The permittee shall conduct the performance test as required under 40 CFR 60.8 using the continuous system for monitoring $NO_X$ under 40 CFR 60.48b to determine compliance with the emission limit for $NO_X$ required under 40 CFR 60.44b. [40 CFR 60.46b(e)]

i. For the initial compliance test, $NO_X$ from the steam generating unit is monitored for 30 successive steam generating unit operating days and the 30-day average emission rate is used to determine compliance with the $NO_X$ emission standard. The 30-day average emission rate is calculated as the average of all hourly emissions data recorded by the monitoring system during the 30-day test period. [40 CFR 60.46b(e)(1

ii. Following the date on which the initial performance test is completed or required to be completed under 40 CFR 60.8, whichever date comes first, the permittee shall upon request determine compliance with the $NO_X$ standards in 40 CFR 60.44b through the use of a 30-day performance test. During periods when performance tests are not requested, $NO_X$ emissions data collected pursuant to 40 CFR 60.48b(g)(1) or CFR 60.48b(g)(2) are used to calculate a 30-day rolling average emission rate on a daily basis and used to prepare excess emissions reports, but will not be used to determine compliance with the $NO_X$ emission standards. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all the hourly $NO_X$ emission data for the preceding 30 steam generating unit operating days. [40 CFR 60.46b(e)(2)]

4. **Monitoring Requirements:**

a. The permittee shall monitor the amount of the natural gas combusted in the unit on a monthly basis [401 KAR 52:020, Section 10, 40 CFR 60.49b(d)(2)].

b. The permittee shall install, calibrate, maintain, and operate CEMS for measuring $NO_X$ and $O_2$ (or $CO_2$) emissions discharged to the atmosphere, and shall record the output of the system [40 CFR 60.48b(b)(1)].

c. The CEMS required under 40 CFR 60.48b(b) shall be operated and data recorded during all periods of operation of the affected facility except for CEMS breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments. [40 CFR 60.48b(c)]

d. The 1-hour average $NO_X$ emission rates measured by the continuous $NO_X$ monitor required by 40 CFR 60.48b(b) and required under 40 CFR 60.13(h) shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the average emission rates under 40 CFR 60.44b. The 1-hour averages shall be calculated using the data points required under 40 CFR 60.13(h)(2). [40 CFR 60.48b(d)]

e. The procedures under 40 CFR 60.13 shall be followed for installation, evaluation, and operation of the continuous monitoring systems. This includes the completion of annual Relative Accuracy Test Audits (RATAs), daily drift checks, and quarterly cylinder gas

## SECTION B - EMISSION UNITS, EMISSION POINTS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

audits in accordance with 40 CFR 60, Appendix B. [40 CFR 60.48b(e), 40 CFR 60.13, 40 CFR 60, Appendix B]

f. When $NO_X$ emission data are not obtained because of CEMS breakdown, repairs, calibration checks and zero and span adjustments, emission data will be obtained by using standby monitoring systems, Method 7 of appendix A of 40 CFR Part 60, Method 7A of appendix A of 40 CFR Part 60, or other approved reference methods to provide emission data for a minimum of 75 percent of the operating hours in each steam generating unit operating day, in at least 22 out of 30 successive steam generating unit operating days. [40 CFR 60.48b(f)]

g. As an alternative to meeting the CEMS requirements of this section, the permittee may elect to monitor steam generating unit operating conditions and predict $NO_x$ emission rates as specified in a plan submitted pursuant to 40 CFR 60.49b(c). [40 CFR 60.48b(g)(2)]

5. **Specific Recordkeeping Requirements:**

a. The permittee shall document the actions during startup period and shutdown periods, including duration of the startup period, by signed contemporaneous logs or other relevant evidence. [401 KAR 59:015, Section 7(1)(d)]

b. The permittee shall maintain records of the amount of the natural gas combusted on a monthly basis [401 KAR 52:020, Section 10, 40 CFR 60.49b(d)(2)].

c. The permittee shall maintain fuel receipts (such as a current, valid purchase contract, tariff sheet, or transportation contract) from the fuel supplier that certify that the fuel meets the definition of natural gas as defined in §60.41b and the sulfur limit (0.32 lb/MMBtu) to preclude the applicability of the 40 CFR 60, Subpart Db $SO_2$ standard. [40 CFR 60.49b(r)(1)]

d. The permittee shall maintain records of the following information for each steam generating unit operating day: [40 CFR 60.49b(g)]

i. Calendar date;

ii. The average hourly $NO_X$ emission rates (expressed as $NO_2$) (ng/J or lb/MMBtu heat input) measured or predicted;

iii. The 30-day average $NO_X$ emission rates (ng/J or lb/MMBtu heat input) calculated at the end of each steam generating unit operating day from the measured or predicted hourly nitrogen oxide emission rates for the preceding 30 steam generating unit operating days;

iv. Identification of the steam generating unit operating days when the calculated 30-day average $NO_X$ emission rates are in excess of the $NO_X$ emissions standards under

# SECTION B - EMISSION UNITS, EMISSION POINTS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

40 CFR 60.44b, with the reasons for such excess emissions as well as a description of corrective actions taken;

v. Identification of the steam generating unit operating days for which pollutant data have not been obtained, including reasons for not obtaining sufficient data and a description of corrective actions taken;

vi. Identification of the times when emissions data have been excluded from the calculations of average emission rates and the reasons for excluding data;

vii. Identification of "F" factor used for calculations, method of determination, and type of fuel combusted;

viii. Identification of the times when the pollutant concentration exceeded full span of the CEMS;

ix. Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3; and

x. Results of daily CEMS drift tests and quarterly accuracy assessments as required under Appendix F, Procedure 1 of 40 CFR Part 60.

**6. Specific Reporting Requirements:**

a. The permittee shall submit notification of the date of initial startup, as provided by 40 CFR 60.7. This notification shall include: [40 CFR 60.49b(a)]

i. The design heat input capacity of the unit and identification of the fuels to be combusted in the unit;

ii. If applicable, a copy of any federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels; and

iii. The annual capacity factor at which the owner or operator anticipates operating the facility based on all fuels fired and based on each individual fuel fired.

b. If the permittee seeks to demonstrate compliance with the $NO_X$ standard through the monitoring of steam generating unit operating conditions in the provisions of 40 CFR 60.48b(g)(2) shall submit to the Administrator for approval a plan that identifies the operating conditions to be monitored in 40 CFR 60.48b(g)(2) and the records to be maintained in 40 CFR 60.49b(g). [40 CFR 60.49b(c)]

c. The permittee shall submit excess emission reports for any excess emissions that occurred during the reporting period. Excess emissions are defined as any calculated 30-day rolling

## SECTION B - EMISSION UNITS, EMISSION POINTS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

average $NO_X$ emission rate, as determined under 40 CFR 60.46b(e), that exceeds the applicable emission limits in 40 CFR 60.44b. [40 CFR 60.49b(h)]

d. For each six (6)-month period of operation, the permittee shall submit reports containing the information recorded under 40 CFR 60.49b(g) as identified by Condition 5.d. These reports shall be postmarked by the thirtieth (30th) day following the end of the reporting period [40 CFR 60.49b(i) & (w)]

   i. In each semiannual report, the permittee shall certify that only natural gas was combusted in the affected boiler during the reporting period. [40 CFR 60.49b(r)(1)]